PB89-127468

Description of the Process Model Projection Technique (PROMPT). Version 3.0

Energy and Environmental Analysis, Inc.
Arlington, VA

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

Oct 88

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA/600/8-88/101	2.
3. RECIPIENT'S ACCESSION NO. PB89 127468/AS	
4. TITLE AND SUBTITLE Description of the Process Model Projection Technique (PROMPT) (Version 3.0)	5. REPORT DATE October 1988
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Tim Hogan	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Energy and Environmental Analysis, Inc. 1655 N. Fort Myer Drive Arlington, Virginia 22209	10. PROGRAM ELEMENT NO.
	11. CONTRACT/GRANT NO. 68-02-4202, Task 10
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Air and Energy Engineering Research Laboratory Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED Task Final; 10/85-3/86
	14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL project officer is Larry G. Jones, Mail Drop 62, 919/541-7716.

16. ABSTRACT The report describes the model logic and data sources for Version 3.0 of the Process Model Projection Technique (PROMPT), one of four stationary source emission and control cost forecasting models developed for the National Acid Precipitation Assessment Program (NAPAP). PROMPT projects air pollution emissions (SO2, sulfates, and NOx) and costs for industrial combustion and industrial processes (e.g., process heaters, furnaces, dryers, kilns, engines, turbines, and wood-fired boilers). PROMPT excludes emissions from the combustion of natural gas, distillate and residual fuel oil, and coal in industrial boilers. The outputs are provided for 1980 (baseline), 1985 (forecasted, not actual), 1990, 1995, 2000, 2010, 2020, and 2030. The data sources used to develop PROMPT Version 3.0 predate the release of the final 1980 NAPAP Emissions Inventory. Compilation errors identified and corrected in these preliminary data prior to publication of the final inventory were not also corrected in the baseline data for Version 3.0. Instead, EPA has chosen to update the baseline emissions data in PROMPT using the more extensively quality assured 1985 NAPAP Emissions Inventory data base (now nearing completion). Version 3.0 of PROMPT has been tested to verify that its source code and algorithms are functioning as intended.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Acidification	Pollution Control	13B	07C
Emission	Nitrogen Oxides	Stationary Sources	14G	07B
Cost Analysis	Sulfur Oxides	Acid Rain	14A	
Forecasting	Industrial Processes	Process Model Projection Technique		13H
Mathematical Models	Sulfates Combustion			21B
Precipitation (Meteorology)			04B	

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 44
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE MF PC A3/A6.95

EPA Form 2220-1 (9-73)

NOTICE

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PB89-127468

EPA/600/8-88/101
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DESCRIPTION OF THE PROCESS MODEL PROJECTION TECHNIQUE (PROMPT) (VERSION 3.0)

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This study was conducted in cooperation with the
National Acid Precipitation Assessment Program

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REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL INFORMATION SERVICE
SPRINGFIELD, VA. 22161

ABSTRACT

The Process Model Projection Technique (PROMPT) is one of four stationary source emission and control cost forecasting models developed by the Air and Energy Engineering Research Laboratory for the National Acid Precipitation Assessment Program (NAPAP). PROMPT projects air pollution emissions (sulfur dioxide, sulfates and nitrogen oxides) and costs for industrial combustion and industrial processes (i.e., process heaters, furnaces, dryers, kilns, engines, turbines and wood-fired boilers). PROMPT excludes emissions from the combustion of natural gas, distillate or residual fuel oil or coal in industrial boilers. The outputs are provided for 1980 (baseline), 1985 (forecasted, not actual), 1990, 1995, 2000, 2010, 2020 and 2030.

This document describes the model logic and data sources for Version 3.0.

The data sources used to develop PROMPT Version 3.0 predate the release of the final 1980 NAPAP Emissions Inventory. Compilation errors identified and corrected in these preliminary data prior to publication of the final inventory were not also corrected in the baseline data for Version 3.0. Instead, EPA has chosen to update the baseline emissions data in PROMPT using the more extensively quality assured 1985 NAPAP Emissions Inventory data base (now nearing completion). Version 3.0 of PROMPT has been tested to verify that its source code and algorithms are functioning as intended. The reader is cautioned to remain aware that the results obtained from this version of PROMPT are subject to change upon release by EPA of the next, updated version using the 1985 data baseline.

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SECTION 1

INTRODUCTION

This report presents the logic, structure and data used in the Process Model Projection Technique (PROMPT). PROMPT is a model developed by Energy and Environmental Analysis, Inc. (EEA) for the U.S. Environmental Protection Agency (EPA) in cooperation with the National Acid Precipitation Assessment Program (NAPAP). By design it is a simple, low-cost model which will provide an initial assessment of the role and magnitude of industrial process emissions in the control of acid deposition SO_x/NO_x precursors.

PROMPT projects the emission of nitrogen oxides and sulfur oxides from industrial sources such as process heaters, wood boilers, furnaces, dryers, kilns, engines and turbines through the year 2030. Projections of emissions from combustion of natural gas, distillate or residual fuel oil or coal in industrial boilers are developed through the companion Industrial Combustion Emissions (ICE) Model.[1] In operating PROMPT (Version 3.0), the user can select one of four predetermined energy and economic scenarios and one of several alternative air pollution control strategies. The model estimates the emissions reduction and cost of the selected strategy.

The purpose in developing PROMPT was to obtain a technique for assessing the role of industrial processes in contributing to acid deposition SO_x/NO_x precursors. As requested by EPA, EEA included in the design goals for PROMPT restrictions that it be easy to use, inexpensive to create and run, and readily transferable to other computer systems. To meet these goals, the model was developed with substantial aggregation of industrial emission sources and control cost information drawing on existing data bases.

Industrial process emissions sources are aggregated into eight emission source groups for SO_x analyses and redistributed into seven other emission source groups for NO_x analyses. For each group, an aggregate emission factor has been assigned. Simple control cost functions are used with each emission source group to estimate emission reductions and control costs. Within some of the emission source groups, actual control options will vary substantially; for others, control methods have not been commercially applied. By necessity, the control cost functions are based on limited data.

SECTION 2

PROMPT MODEL LOGIC

Figure 1 illustrates the major steps employed in the preparation and operation of PROMPT. PROMPT is designed to perform three functions:

1) For a selected fuel demand projection, estimate NO_x or SO_x baseline emissions (without acid deposition control initiatives).
2) Compute emissions reduction and control costs to meet a user-specified NO_x or SO_x emission control strategy.
3) Generate summary output tables of emissions and control costs, plus a machine readable data file that meets the input requirements of another NAPAP model, the Emissions Strategy Integration Model (ESIM).

The model execution steps and the required data inputs for PROMPT are described below:

1) NAPAP Energy/Economic Scenario: The industrial fuel demand in PROMPT is based upon alternative energy/economic scenarios developed by Argonne National Laboratory (ANL) for the 1985 NAPAP Model Set Test Runs. The NAPAP driver data used indirectly in PROMPT consists of regional industrial production indices by SIC code for 1980 through 2030, and regional industrial energy prices through the year 2045. Three sets of driver data are utilized from NAPAP's 1985 "reference," "low," and "high" cases. A fourth case was prepared in 1986 with the 1986 EEA middle oil price case and the NAPAP 1985 low economic growth rates.
2) ISTUM-2 Model Runs: PROMPT uses industrial energy demand projections generated by EEA's Industrial Sector Technology Use Model (ISTUM-2). ISTUM-2 is a process engineering model of the industrial sector that allows for technology competition at a detailed process level. Driven by the energy/economic scenarios, the model provides a forecast of the mix of fuels used by the industrial sector on a regional basis.
3) Industrial Process Fuel Use Demand Projections: The ISTUM-2 energy demand projections for the four cases are entered into PROMPT as permanent input data files. Excluded are ISTUM-2 forecasts of natural gas, distillate fuel oil, residual fuel oil and coal demand in industrial boilers. Before the data is entered, the Btu's of fuel demand are aggregated into the broad categories defined as emission source groups. Emission source groups exist separately for NO_x emissions versus sources of SO_x emissions. Table 1 contains a list of the NO_x and SO_x emission source groups in PROMPT.

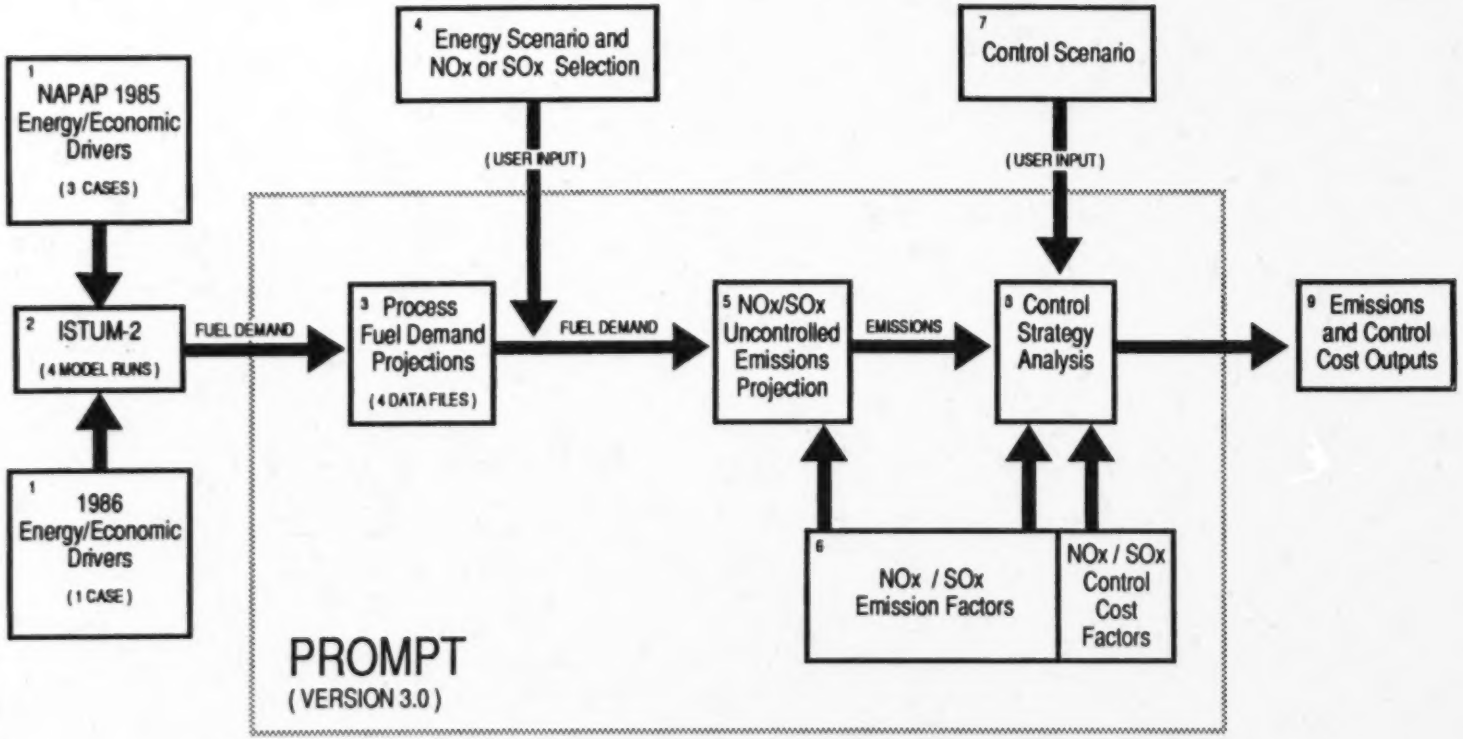

Figure 1. PROMPT Model logic.

TABLE 1. PROMPT EMISSION SOURCE GROUPS

Pollutant	Group	Emission source group
SO_x	1	Smelters*
	2	Coke ovens
	3	Cement kilns
	4	Pulp liquor recovery
	5	Sulfur processing*
	6	Petroleum cracking
	7	Agglomeration
	8	Other fuel uses not covered above**
NO_x	9	Process heaters with high temperature recuperators
	10	Process heaters with low temperature recuperators
	11	Glass melting
	12	Cement kilns
	13	Turbines and engines
	14	Fluid bed combustors+
	15	Other fuel uses not covered above++

* Based on exogenous assumptions; not generated in PROMPT using fuel demand dependent emission factors.

** Examples include refinery heaters, steel reheat furnaces, soaking pits, drying operations, glass manufacturing, and industrial turbines.

\+ Fluid heating, not steam generation.

++ Examples include process heaters without preheat devices, such as brick furnaces, chemical heaters, and low temperature dryers (i.e., food plants); coke ovens; pulp/paper recovery burners; and secondary steel mills.

4) Energy Scenario and Pollutant Selection: To initiate a model run, the user specifies: 1) one of the four fuel demand scenarios, and 2) the pollutant to be forecast (either NO_x or SO_x). The model performs only NO_x or SO_x emissions calculations. To project both pollutants, PROMPT must be run twice.

5) NOx or SOx Uncontrolled Emissions: For each emission source group, NO_x or SO_x emission factors are applied to the Btu's of fuel demand. The emission factors generally vary by fuel type except for emission source groups that emit significant amounts of process-related emissions rather than fuel-related emissions. It should be noted that SO_x emissions in two source groups, Smelters and Sulfur Processing, are not derived from energy demand data. SO_x emissions originating in these two emission source groups are primarily non-fuel-related. These emissions data are an exogenous input.

6) NOx and SOx Emission Factors: Uncontrolled emission factors that vary by emission source group and fuel type have been estimated for use in PROMPT. Controlled emission factors have also been developed where control options are considered feasible. The number of control levels in the model varies with the emission source group.

7) Air Pollution Control Scenario Inputs: The model user has the option of selecting from a set of air pollution control strategies to evaluate the potential NO_x or SO_x emission reductions and the resulting cost of pollution control. The strategic options include a uniform percent reduction for each emission source group, a uniform emissions limit, an aggregate percent or amount of reduction, or control to a specified level of cost-effectiveness (annualized cost increase per unit of emission reduction).

8) Air Pollution Control Strategy Analysis: PROMPT computes the potential emission reductions and control costs for the strategy selected by the model user. For certain control strategies this requires the iterative analysis of the most cost-effective control options for several emission source groups. If no control strategy is selected, this part of PROMPT is bypassed. The methodology for assessing alternative air pollution control strategies in PROMPT is explained in Section 5.

9) Emission and Control Cost Outputs: NO_x or SO_2 emissions, plus air pollution control costs for a selected control strategy, are provided at a regional level, by emission source group and disaggregated to a State-level in a data file consistent with the input requirements of another NAPAP model. Primary sulfate emissions are also computed by State and by region, assuming that two percent of SO_2 emissions are emitted as sulfates. The emission/cost outputs are generated for 1980 (base year), 1985 (projected, not actual), 1990, 1995, 2000, 2010, 2020, and 2030.

PROMPT Version 1.0 was completed in November 1984. Its key features were:

- 1980 base year
- 1985 - 2000 forecast period
- three EEA preliminary fuel demand files

PROMPT Version 2.0 was completed in September 1985 and this version included the three 1985 fuel demand scenarios* and an extended forecast period to 2030.

Version 3.0 of PROMPT includes the fourth fuel demand scenario (based on the 1986 EEA middle oil price case)** and was completed in October 1986.

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* The three 1985 fuel demand scenarios in Versions 2.0 and 3.0 are not the same as the three EEA preliminary fuel demand files in Version 1.0; the three EEA preliminary fuel demand files in Version 1.0 are not available for Versions 2.0 and 3.0.

**In addition to the three 1985 fuel demand scenarios.

SECTION 3

INDUSTRIAL PROCESS FUEL DEMAND PROJECTIONS

For most industrial NO_X and SO_X emission sources, the amount of pollutants released is directly dependent on fuel use. Therefore, the assumptions used in projecting industrial fuel use greatly affect the resultant emissions.

PROMPT uses four industrial fuel demand projection inputs. These energy demand forecast inputs are based on outputs from EEA's Industrial Sector Technology Use Model (ISTUM-2).

As part of the 1985 NAPAP model test runs program, three economic and energy scenarios were created to test the set of models that estimate future levels of NO_X and SO_X emissions from the industrial sector, electric utility sector, and other important sectors of the U.S. This model set, which includes PROMPT, uses the test scenarios to forecast base case NO_X, SO_X and VOC emissions from 1985 through 2030.

Argonne National Laboratory (ANL) has developed the 1985 high, reference, and low growth input files for the NAPAP models. These input files are based primarily on aggregate economic growth rates from Data Resources, Inc. (DRI) macro model projections and fuel price forecasts from preliminary U.S. Department of Energy forecasts. ANL has provided regional- and industry-level data needed to run ISTUM-2. The ANL detailed forecasts provide the industrial production indices and fuel price data required to project fuel demand used in PROMPT. These model test scenarios are characterized overall by a range of economic growth rates and increases in fuel prices. These three cases are described further in two separate reports.[2,3]

A fourth scenario is also available. This fourth case is based on the 1986 EEA middle oil price forecast[4] and the 1985 low economic growth projection.

The Industrial Sector Technology Use Model (ISTUM-2) is an engineering economic model developed by EEA to investigate future technological choices in the industrial sector. ISTUM-2 generates future energy needs and the mix of fuels associated with the production of goods and services in the industrial

sector. The model accounts for competition between technologies, changes in the level and mix of economic activity, the price of fuels and capital, and the characteristics of energy-using processes. Central to the creation of ISTUM-2 was extensive technology characterization and market profiling tasks which permit the calculation of these factors with great detail. The industrial sector is characterized by different industrial processes that encompass 27 industry group categories and 18 distinct fuel types. Over 400 technologies compete in numerous market segments to provide the energy services required by this diverse sector.[5]

ISTUM-2's major inputs are projected fuel prices by fuel type, Federal region (Figure 2) and year; and industrial production growth rates by industry, Federal region and year.

The fuel demand data base in PROMPT is a direct condensation and simplification of ISTUM-2 output. ISTUM-2 output is simplified in three ways:

1) The energy demand data is limited to industrial process fuel uses and only to the fuels that impact on NO_x and SO_x emissions:

   - Natural gas and LPG
   - Distillate fuel oil
   - Low and high sulfur residual fuel oil
   - Low and high sulfur coal
   - By-product and waste fuels and biomass (includes refinery gas, blast furnace gas, coke oven gas, bark and wood, and other non-fossil fuels)

   Electricity, steam, petrochemical feedstock demands, and fossil fuels (natural gas, fuel oil or coal) co-fired with by-product, waste, or biomass fuels in industrial boilers are excluded from PROMPT. Their impacts on NO_x and SO_x emissions are captured by other NAPAP models.

2) Information on the vintage of the fuel combustion equipment is reduced to the five-year interval in which the equipment was constructed. In order to apply air pollution control regulations at different times and to take into account the difference in control costs between new and existing sources, it is necessary for energy use and the associated equipment to be segmented by year of construction. For example, if a regulatory strategy is begun in 1990, sources on-line prior to 1990 are assessed costs associated with

REGION NAMES

1. New England
2. New York/New Jersey
3. Middle Atlantic
4. South Atlantic
5. Midwest
6. Southwest
7. Central
8. North Central
9. West
10. Northwest

Figure 2. Federal regions of the United States.

retrofit applications, and sources built after 1990 are assessed the cost of new construction.

3) PROMPT contains an aggregation of the ISTUM-2 energy demand distribution by type of industry. In fact, PROMPT contains two separate aggregations of the total industrial fuel demand: one based on NO_x emission characteristics and one based on SO_x emissions characteristics. Emission source groups were created on the following basis:

   - Similarity of emission categories: The sources within a category have similar emission factors for each of the fuels used.
   - Control devices and cost-similarity: The source types are able to use similar control technologies; these technologies reduce emissions by a similar amount and have similar costs for sources in the group.
   - Significance of emissions: Each category covers the largest portion of total emissions or some significant change in emissions.

Total industrial fuel demand has been aggregated into eight sulfur oxides emission groups. The description of the SO_x emission source groups and the rationale for their creation are presented in Table 2. Table 3 provides similar information on the seven NO_x emission source groups.

PROMPT is restricted to non-boiler fuel use with a few exceptions: it does include steam generated in industrial cogeneration combined cycle plants and steam generated in waste boilers (CO boiler, wood, coke oven gas, blast furnace gas, still gas, and black liquor recovery systems). PROMPT does not include demand for natural gas, distillate fuel oil, residual fuel oil and coal in industrial boilers; they are developed through the companion Industrial Combustion Emissions (ICE) Model.[1]

When the simplification of ISTUM-2 output is complete, the PROMPT input data file provides the fuel demand used in each emission source group, fuel type, construction period, Federal region, and years: 1980 (base year), 1985 (projected, not actual), 1990, 1995, 2000, 2010, 2020, and 2030. The ISTUM-2 industrial energy demand forecasts for the three 1985 NAPAP test cases are summarized in two separate reports.[2,3]

TABLE 2. PROMPT EMISSION SOURCE GROUPS FOR SULFUR OXIDES

Source group	Category description	Sources	Common features
1	Smelters	Non-ferrous smelters - copper, zinc	Emissions are linked to ore sulfur content and are large
2	Coke ovens	Coke production	Emissions are linked to the coal being coked
3	Cement kilns	Cement and lime kilns	Emissions are limited by reactions with product material
4	Pulp liquor recovery	Burning of black liquor in Kraft pulping	Emissions are linked to the material being processed
5	Sulfur processing	Sulfuric acid and sulfur plants	Emissions are determined by the process rate, not the fuel use
6	Petroleum refinery cracking	Fluid cat cracking, hydrocracking, coking, and associated CO boilers	Emissions are linked to the process operation severity and the crude being processed
7	Agglomeration	Iron ore sintering and pelletizing	Emissions are linked to ore quality
8	Other fuel uses	Miscellaneous fuel burning systems*	Emissions are a direct function of fuel sulfur content

* Excluding demand for natural gas, distillate fuel oil, residual fuel oil and coal in industrial boilers.

TABLE 3. PROMPT EMISSION SOURCE GROUPS FOR NITROGEN OXIDES

Source group	Category description	Sources	Common features
9	High temperature preheated furnaces	Furnaces above 649°C (1200°F) preheat using recuperators or regenerators -- steel reheat, forging, and aluminum melters	Preheating increases the peak combustion and resultant NO_x emissions are higher
10	Low temperature preheated furnaces	Furnaces with 427-649°C (800-1200°F) preheating and conventional recuperators and regenerators	Preheating increases combustion temperatures, producing higher NO_x emissions
11	Glass melting	Fossil fuel-fired reverberatory furnaces and unit melters	Emissions are determined by the process design
12	Cement	Cement and lime kilns	Emissions are linked to the process design
13	Turbines and engines	Gas turbines and internal combustion engines used in cogeneration	NO_x controls are different for combustion in these systems
14	Fluid bed combustors	Uses of fluidized bed combustors for fluid heating (not steam generation)	FBC yields uniform low combustion temperatures and different NO_x emission characteristics
15	Other fuel uses	Miscellaneous other fuel uses including conventional heaters, dryers, and furnaces without preheat*	Conventional fuel-fired dryers, furnaces and heaters have similar NO_x emission control options

* Excluding demand for natural gas, distillate fuel oil, residual fuel oil and coal in industrial boilers.

SECTION 4

BASELINE EMISSIONS

Since the purpose of PROMPT is to provide a simplified method for forecasting emissions and control costs, the level of detail in the emission data has been reduced. The NO_x and SO_x emission factors for each aggregate emission source group are derived from emission rates specified for various individual energy use categories within ISTUM-2. Combining the ISTUM-2 categories does create several problems. By compressing several categories into one, differences in the emission factors within the group are lost. In the case of SO_x and NO_x emissions, it is reasonable to combine the ISTUM-2 source categories because the number of source categories that emit both fuel-related and process-related emissions is limited.

SO_x EMISSIONS

The SO_x emission source categories are based on dividing sulfur emitting sources into two general classes: 1) where the sulfur emissions are a function of the sulfur content of the fuel consumed, and 2) where the emissions are due to the process. The categories with SO_2 emissions due to the process are:

- Smelters
- Sulfuric acid/sulfur production
- Coke ovens
- Cement
- Petroleum refining -- cracking and coking
- Iron ore agglomeration.

For all other source types, sulfur emissions are assumed to be due to the fuel burned.

Because of data base size constraints, ISTUM-2 separates residual fuel oil and coal into only two categories: high and low sulfur. High sulfur residual fuel oil is defined as over 1.0 percent and low sulfur residual fuel oil is less than one percent. Emission factors for all fuel use, as well as those for process sources, were based on AP-42.[6]

Table 4 shows the assumed uncontrolled SO_x emission factors. For simplicity, these emission factors have been expressed as a function of fuel input since the production rate generally varies according to fuel input.

The "other" category includes fuel combustion in all sources other than those specifically indicated. Most fuel use is in this category since most SO_x emissions are the result of sulfur in the fuel. How the fuel is burned does not significantly affect the amount of SO_x released.

Nonferrous smelters, sulfuric acid plants, and sulfur recovery units are handled as special categories in PROMPT. Smelter emissions are treated exogenously since they are under special regulatory control and are expected to have significant emission reductions regardless of any control required under any type of control program. Future emission estimates by State for 1990 and 2000 are taken from the U.S.-Canada Work Group 3B report.[7] Smelter SO_2 emissions are expected to decrease to 630 thousand metric tons/year (694 thousand short tons/year) by 1990 and drop further in year 2000 to 546 thousand metric tons/year (602 thousand short tons/year).

Emissions estimates for sulfuric acid plants and sulfur production plants are taken from a preliminary version of the 1980 NAPAP inventory.[8] The 1980 national emissions for sulfuric acid plants and sulfur production are 288 thousand metric tons/year (318 thousand short tons/year) and 278 thousand metric tons/year (306 thousand short tons/year), respectively. Their emission levels have been assumed to remain constant over time.

NO_x EMISSIONS

Baseline uncontrolled NO_x emission factors are shown in Table 5. Each of the categories shown on Table 5 is a mixture of different source types that have some characteristics in common. For example, most industrial sources produce NO_x through the combustion of fuel with little or no combustion air preheat (e.g., 260°C (500°F) or less). These sources have similar NO_x emission factors. All of this fuel consumption is compressed into the PROMPT sector

TABLE 4. UNCONTROLLED SO_x EMISSION FACTORS*
ng/J (lb/10^6 Btu)

Emissions Source Group	Natural Gas	L.S. Oil	L.S. Coal	H.S. Oil	H.S. Coal	Other Gas	Other	Biomass	Distillate	LPG
"Other fuel combustion"	0 (0)	382 (0.9)	552 (1.3)	977 (2.3)	1,062 (2.5)	98 (0.23)	-- --	-- --	64 (0.15)	-- --
Coke oven	-- --	-- --	-- --	-- --	-- --	-- --	30** (0.07)	-- --	-- --	-- --
Kraft recovery furnaces	-- --	-- --	-- --	-- --	-- --	-- --	-- --	85 (0.2)	-- --	-- --
Cement	765 (1.8)	1,148 (2.7)	1,148 (2.7)	2,150 (5.0)	-- --	-- --	1,148 (2.7)	-- --	-- --	-- --
Petroleum refining cracking	935 (2.2)	-- --	-- --	935 (2.2)	-- --	935 (2.2)	935 (2.2)	-- --	935 (2.2)	-- --
Agglomeration	680 (1.6)	-- --	680 (1.6)	680 (1.6)	-- --	-- --	680 (1.6)	-- --	-- --	-- --

* Dashes in the table indicate that fuel use is negligible in that emissions source group.

** Metallurgical coal.

TABLE 5. UNCONTROLLED NO_x EMISSION FACTORS*
ng/J (lb/10^6 Btu)

Emissions Source Group	Natural Gas	L.S. Oil	L.S. Coal	H.S. Oil	H.S. Coal	Other Gas	Other	Biomass	Distillate	LPG
"Other fuel combustion	85 (0.2)	179 (0.42)	272 (0.64)	187 (0.44)	272 (0.64)	179 (0.2)	-- --	64 (0.15)	81 (0.19)	81 (0.19)
High temperature recuperators	1,360 (3.2)	1,445 (3.4)	-- --	1,530 (3.6)	-- --	-- --	-- --	-- --	1,360 (3.2)	-- --
Low temperature recuperators	306 (0.72)	374 (0.88)	527 (1.24)	442 (1.04)	-- --	-- --	-- --	-- --	306 (0.72)	-- --
Glass melting	340 (0.8)	412 (0.97)	-- --	-- --	-- --	-- --	-- --	-- --	340 (0.8)	-- --
Cement	1,785 (4.2)	850 (2.0)	510 (1.2)	-- --	-- --	-- --	510 (1.2)	-- --	850 (2.0)	-- --
Turbines and engines	175 (0.41)	276 (0.65)	-- --	-- --	-- --	175 (0.41)	-- --	-- --	175 (0.41)	-- --
Fluidized bed combustors	-- --	-- --	129 (0.3)	-- --	129 (0.3)	-- --	-- --	-- --	-- --	-- --

* Dashes in the table indicate that fuel use is negligible in that emissions source group.

labeled "other sources." Sources included in this category are conventional refinery heaters, metal melting furnaces, dryers, and almost all types of direct and indirect heaters used in industry.

When the combustion air preheat temperature rises, NO_x emissions increase exponentially. For this reason, two categories have been established that include all sources using high temperature combustion air. Based on available data, it appears that the temperature of the preheated combustion air is far more important in determining the level of NO_x emissions than the type of furnace. Therefore, all furnaces with preheaters (regardless of type) are included in these groups. These sources include metal melting and metal treating furnaces, as well as drying furnaces, which have high temperature exhaust.

Separate source categories have been established for glass melting, cement manufacturing and industrial gas turbines and engines. Because of their extremely high temperature processes, both the glass and cement industries have different NO_x emissions characteristics than other NO_x emissions sources. The cement source group includes lime calcining as well as cement manufacturing. For cement, the emission factor used is one developed by KVB[9] and assumes the majority of energy use is in conventional cement kilns.

Table 5 shows the estimated uncontrolled emission rate used in each source category by fuel type. The NO_x emission factors were originally derived from a variety of sources. For NO_x emissions from furnaces which have the potential to use high temperature combustion air preheating, emission factors were developed by GCA.[10] GCA based its estimates on all available data, most of which were obtained from bench and sub-pilot scale furnaces. Test data were not available for furnaces with extremely high temperature (1093°C or 2000°F) preheat. Estimates for these sources had to be extrapolated from lower temperature data. In addition, the data were extremely limited in quantity and did not represent all possible furnace and burner configurations.

NO_x emission data for other source categories were taken from a number of sources including AP-42[6] and NSPS documents[11] (for example, liquor recovery process heaters). All NO_x emission sources except for those affected by NSPS

were assumed to be uncontrolled. NO_x emission factors vary by fuel type in most emission source groups.

It is important to keep in mind the extremely limited amount of data available on NO_x emissions from industrial non-boilers. Historically there has been little concern over NO_x emissions from this source category for a variety of reasons. Most importantly, most non-boiler fuel use has been relatively clean natural gas. In the future, shifts to more oil (higher NO_x emission rate) and the application of very high combustion air preheat on some source categories may substantially increase NO_x emissions. Most of the emission data in PROMPT are based on data either extrapolated from boilers or on data from a very limited data base.

SECTION 5

EMISSIONS/CONTROL STRATEGY ANALYSIS

The emissions and control strategy steps use energy data to calculate pollutant emissions and the cost of a desired control option. These modules supply all data inputs needed to compute emissions and their control costs.

The rather simplified purpose of these is to take information on the desired control strategy and transform a group of curves, which show the cost of control as a function of unit emission rate, into a set of emission factors. These emission factors are applied to the energy data provided by the initial component of PROMPT. The unit air pollution control costs associated with each of the chosen emission factors can then be used with the same energy numbers to calculate control costs.

STRUCTURE AND USE OF COST CURVES

Cost curves establish a relationship between the cost of control and emission rates. For most of the sources in this study, the word "curve" is actually a misnomer. Most of the data is expressed as a step function with one to three steps. For each source category (e.g., process heaters with high temperature recuperators), as many as 40 cost curves may be required. For each of ten fuel types, four curves may be necessary:

1) Air pollution control capital cost of new installation.
2) Air pollution control capital cost of retrofit installation.
3) Air pollution control annualized cost (including capital and O&M) of new installation.
4) Air pollution control annualized cost (including capital and O&M) of retrofit installation.

In developing the cost curves, a large number of simplifying assumptions have been made. A more detailed discussion of these assumptions follows in Section 6. In brief, simplifications were made to fit the data into a form which could be used readily in the model. First, capital costs were based on an average sized source in each group, and a linear relationship between size and cost was assumed. Second, an average capacity utilization rate was

assumed. These assumptions allow air pollution control cost figures to be expressed on a $/kJ ($/Btu) capacity basis and to be used easily with the energy demand projections developed in each emission source group. While separate curves for capital and annual costs exist, the analysis of which sources to control is performed using the annualized costs. Corresponding capital costs were then tallied.

The cost curves are used in the following manner. Figure 3 is a sample cost curve. Point A represents the uncontrolled condition. At Point A, the emission rate has no associated cost of control. Point B represents the first control level; the emission rate is decreased and there is an associated cost. Points C and D represent more stringent control options. The appropriate point on the cost curve is found by moving along the curve from one control level to the next until a point which meets the control strategy criteria is found or until all the possible options are exhausted. No intermediate emission rates are assumed possible. In the example only points A, B, C, or D could be selected.

All of the cost curves are based on independent control technologies, and movement from point to point can be made without consideration of the previous steps.

CONTROL STRATEGY ALTERNATIVES

The air pollution control cost curves are utilized differently, depending upon the control strategy option selected by the user. The following types of strategies can be used:

Strategy	Description
1) Uniform Percent Reduction	Emissions of each source group are reduced by the same specified percentage
2) Emission Limit	The emissions of each source group are limited to a specified rate
3) Cost-effectiveness Limit	The cost of control is limited to a specified ratio ($/kg or $/lb)

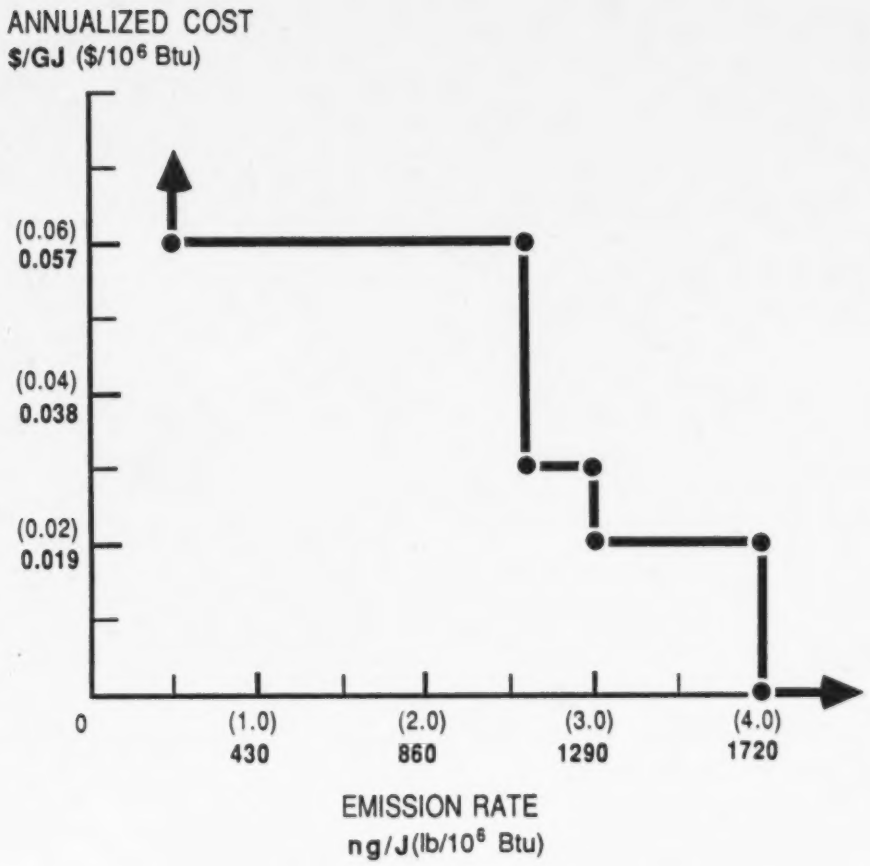

Figure 3. Sample cost curve.

4) Aggregate Percent Reduction — The total emissions are reduced by a specified percentage

5) Aggregate Amount Reduction — The total emissions are reduced by a specified amount

The control strategies represent alternative methods of acid deposition regulation. These strategies vary in complexity.

Uniform Percent Reduction

The uniform percent reduction strategy requires that all sources reduce emissions by a specified percentage. This strategy is implemented within the model by using the appropriate cost curve for each source and fuel type and then choosing the most suitable control level. For example, suppose a 20 percent reduction in emission rate were required of the source and fuel group of Figure 3. The uncontrolled rate is 1,720 ng/J (4 lb/10^6 Btu). The first control level emission rate is 1,290 ng/J (3 lb/10^6 Btu). This is a reduction of 25 percent. With the required reduction of 20 percent rather than 25 percent, the model still selects the first control level since no intermediate emission rates are assumed to be possible. If the required reduction were 90 percent the model would test each control level in turn. The last control level (D) has an overall emissions reduction of 88 percent. The model would select this control level although it does not meet the prescribed emission rate since this is the maximum degree of control possible.

Emission Limits

This strategy requires all sources to meet specific emission rates. The model selects the least restrictive control level which has an emission rate at or below the specified limit. If the desired rate cannot be matched, the model chooses the highest degree of control possible.

Cost-Effectiveness Limit

Using the cost-effectiveness strategy, all the controls which meet a specified cost-effectiveness are applied. The cost-effectiveness of a given step is the quotient of the annualized cost associated with that step divided by the difference in the controlled and the uncontrolled emission rates. For

example, in Figure 3, control level 1 has an annual cost of 1.9¢/GJ (2¢/10^6 Btu). The difference in the uncontrolled and the controlled emission rates is 429 ng/J (1.0 lb/MMBtu). The cost-effectiveness ratio is 0.04 dollars/kg (0.02 dollars/lb). If the specified cost-effectiveness ratio were greater than 0.04 dollars/kg (0.02 dollars/lb), the model first selects control level 1 and then tests control level 2 to see if it is acceptable. If the specified cost-effectiveness were less than 0.04 dollars/kg (0.02 dollars/lb), this source would remain uncontrolled. The cost-effectiveness strategy implements the most stringent control level possible within the given cost-effectiveness limit.

Aggregate Percent Reduction

The aggregate percent reduction strategy calculates the marginal cost-effectiveness of moving from the current control level to the next. The model implements the most cost-effective step from among all fuel types and all emissions source groups and then compares the emissions reduction with the total uncontrolled emissions. If the percent reduction is less than the specified percentage, the model continues to implement control steps in order of their cost-effectiveness until the required percent reduction is reached or until all of the control options are exhausted.

Aggregate Amount Reduction

The aggregate amount reduction strategy uses the same selection mechanism as the aggregate percent reduction strategy. This strategy compares the reduction in emissions with a specified amount instead of the percentage. The model implements one control step at a time until the strategy criteria are met or until all the control steps have been taken.

SECTION 6

EMISSIONS CONTROL COSTS

This section presents the air pollution control cost and effectiveness estimates used in PROMPT to evaluate various NO_x and SO_x emissions control strategies.

SO_x EMISSION CONTROLS

The most practical way to reduce SO_x emissions from process heaters is to switch to a lower sulfur content fuel. Table 6 provides estimates of the average cost to move from high to low sulfur fuels.[12] It should be noted that in PROMPT there are no capital costs associated with these shifts to lower sulfur fuels. Switches between fuel types, i.e., from oil to gas or from coal to oil, are not allowable control strategies. Flue gas desulfurization (FGD) is considered for process heaters. The costs to apply FGD to these sources are shown in Table 7.[13]

Several significant SO_x emission sources have emissions which are only the result of process operations or the process and fuel use combined:

- Coke ovens
- Iron ore agglomeration
- Petroleum refining, cracking, and coking
- Cement.

For coke ovens and iron ore agglomeration, PROMPT estimates uncontrolled emissions only. No proven control technology is available, and the application of FGD (which could reduce emissions) is expected to be too expensive.

For some petroleum refining cracking operations, FGD systems have been applied as a control option. PROMPT assumes that a once-through sodium-based system would be used and that costs would be similar to its application for industrial boilers.[13] Table 8 shows the assumed costs.

Cement produces SO_2 emissions both from the combustion of fuel and sulfur contained in the raw feed. It is possible to reduce emissions by using a lower

TABLE 6. FUEL DESULFURIZATION COSTS FOR "OTHER SOURCES"

Fuel type	SO_2 emissions rate ng/kJ (lb/MMBtu)	SO_2 emissions reduction (%)	O&M control costs 1980 $/GJ ($/MMBtu)
High Sulfur Oil-fired heater	0.99 (2.3)	0	-- --
	0.77 (1.8)	22	0.09 (0.10)
	0.64 (1.5)	35	0.23 (0.24)
	0.52 (1.2)	48	0.34 (0.36)
	.39 (0.9)	61	0.45 (0.48)
Low Sulfur Oil-fired Heater	0.39 (0.9)	0	-- --
	0.30 (0.7)	22	0.11 (0.12)
	0.21 (0.50)	44	0.23 (0.24)
	0.15 (0.35)	61	0.34 (0.36)
Coal-fired heater	1.07 (2.5)	0	-- --
	0.56 (1.3)	48	0.07 (0.07)
	0.47 (1.10)	56	0.19 (0.20)

TABLE 7. SO_2 EMISSION CONTROL COST DATA FOR "OTHER SOURCES"

Control device	SO_2 emissions reduction (%)	Fuel type	Costs (1980 $)* Capital New	Capital Retrofit	O&M
Flue gas desulfurization	90	High sulfur residual fuel oil	525,000	675,000	260,000
	90	Coal	525,000	675,000	345,000

*Based on an average size of 22 MW (75 MMBtu/hr) and 7,000 hours of operation.

TABLE 8. SO_2 EMISSION CONTROL COST DATA FOR PETROLEUM REFINING CRACKING UNIT

Control device	SO_2 emissions reduction (%)	Costs (1980 $)*		
		Capital		
		New	Retrofit	O&M
Flue gas desulfurization	90	660,000	850,000	390,000

*Based on average size of 44 MW (150 MMBtu/hr) and 7,000 hours of operation.

sulfur fuel but this will not reduce process emissions. Costs for fuel switching are the same as for the "other" category.

NO_x EMISSION CONTROLS

This section provides a discussion on the control technology assumed to be available and the cost and NO_x emission removal efficiency of each technology for new and retrofit situations.

Control of Miscellaneous Sources

The "other" emission source group includes all process heaters and furnaces other than those in specific source categories. Although these heaters and furnaces vary tremendously in their design and production processes, the extremely limited information available indicates that the NO_x emission rates and air pollution control characteristics are not substantially different and, given the model's simplified approach, can be grouped together.[10] The data are extremely limited, are not of the quality generally used in determining costs, and are being extrapolated beyond their limits. However, since the purpose of PROMPT is to provide a simplified framework to assess the significance of process emissions and not to provide detailed emissions and cost outputs, these data may be adequate.

Three levels of control have been selected for the "other" NO_x emission sources. They are:

- Low Excess Air (LEA): Reducing levels of excess air can reduce NO_x emissions by large amounts (up to 40 percent) on some furnaces, such as natural draft kilns, and by lesser amounts on other furnaces. A 15 percent reduction has been assumed to be achievable by most furnaces. This technique is applicable to both new and existing furnaces. For new furnaces, the technique can be incorporated into the basic design at no cost. Note that one potential problem with any combustion modification technique is that the application of the control may modify the flame pattern and the heat distribution within the furnace.
- Low NOx Burners: It is possible to design burners which incorporate all combustion modification techniques such as LEA, staged combustion, etc. Most of these techniques operate on thermal NO_x and do not control fuel NO_x. For purposes of this paper, low NO_x burners are assumed to reduce thermal NO_x emissions by 25 percent.

- Tail Gas Clean Up: It is possible to use devices such as Selective Catalytic Reduction (SCR) to reduce NO_x emissions from most flue gas streams. It has been used in Japan on boilers and some process sources, and it has been applied in the U.S. at a few facilities in California. Since this technique has very limited current application, cost data is even less available than for other types of control. In addition, the small size of many existing furnace types and space constraints may make retrofit more difficult than for boilers. However, SCR does have one advantage over other control techniques -- it does not affect the flame pattern or operation of the furnace. SCR is also effective to 90 percent control.

Very little data are available on the cost of control on industrial processes. The cost data used in this report are based on the control of NO_x emissions from industrial and utility boilers.[14,15] While the accuracy and validity of the assumptions are certainly open to question, the order of magnitude is probably accurate. Tables 9 and 10 show the costs assumed.

High Temperature Preheat Source Controls

These sources include furnaces and kilns that use or are projected to use air preheat systems to provide combustion air at temperatures of up to 1093°C (2000°F). Due to the high preheat temperature, these sources have the potential for very high NO_x emissions. However, the high temperature recuperators can reduce fuel use by up to 56 percent[16] and, therefore, interest in the continued development of these devices exists. Unfortunately, the data base on NO_x emissions from these devices is very limited and, for the highest temperature preheaters, must be established by: 1) extrapolating emission tests on lower temperature preheaters, and 2) knowledge regarding the relationships between NO_x emissions and combustion temperature.[10]

Data on the control of sources with high temperature preheaters are more scarce than the information on emission rates. Limited results from experiments conducted by the Institute of Gas Technology for the Gas Research Institute have show that, in a pilot scale operation, it is possible to develop a burner that provides all of the benefits of preheat with substantially lower NO_x emissions.[17] This burner has been operated at preheat temperatures up to 760°C (1400°F). For PROMPT, it has been assumed that this burner can be

TABLE 9. NO_x EMISSION CONTROL COST DATA FOR "OTHER SOURCES": OIL AND GAS COMBUSTION

Control device	NO_x emissions reduction (%)		Costs (1980 $)*		
			Capital		
	Oil	Gas	New	Retrofit	O&M
LEA	11	15	0	5,000	0
New low NO_x burner	16	25	10,000	50,000	0
SCR	90	90	500,000	625,000	180,000

*Based on an average of 15 MW (50×10^6 Btu/hr) and 7,000 hrs/yr of operation.

TABLE 10. NO_x EMISSION CONTROL COSTS FOR "OTHER SOURCES": COAL COMBUSTION

Control device	NO_x emissions reduction (%)	Costs (1980 $)*		
		Capital		
		New	Retrofit	O&M
LEA	15	0	5,000	0
New low NO_x burner	25	10,000	50,000	0
SCR	90	520,000	650,000	197,000

* Based on an average size of 15 MW (50 x 10^6 Btu/hr) and 7,000 hours of operation.

developed and applied to all high temperature recuperated sources. Using this burner, a 35 percent reduction in emissions can be achieved.

Since a control device for this category is not well defined, cost data are practically nonexistent. Preliminary information indicates that costs will range from 110 percent to 200 percent of the cost of a normal high temperature burner. For purposes of this study we have assumed that the low NO_x burner is equal to 150 percent of the cost of a normal burner. Table 11 shows the costs assumed in this study. Identical costs have been assumed for both recuperator emission source groups.

Miscellaneous NOx Emission Sources

Several categories of NO_x emission sources require special treatment because of different emission characteristics. These categories include: cement and lime plants, gas turbines and glass plants. Cement and glass plants have higher NO_x emissions than other fuel burning sources due to their high temperature production environment and significant fuel use. Gas turbines ordinarily and necessarily run with extremely large amounts of excess air and consequently have higher NO_x emission rates.

Although the cement and glass industries have NO_x emission characteristics different from other fuel burning sources, the same control techniques appear to be applicable -- i.e., low excess air and low NO_x burners.[14,15] These techniques have been discussed above.

For gas turbines, combustion modifications (called dry control) are assumed to provide up to 30 percent reduction on both new and existing sources. Water injection into the combustion chamber is assumed to provide up to 70 percent reduction for both new and existing sources.[18]

Tables 12 and 13 show the costs assumed for these emission source groups. As with other groups, the cost data are not well established but are considered adequate for purposes of PROMPT.

TABLE 11. NO_x EMISSION CONTROL COST DATA FOR "RECUPERATORS"

Control device	NO_x emissions reduction (%)		Costs (1980 $)*		
			Capital		
	Oil	Gas	New	Retrofit	O&M
New burner	28	30	20,000	50,000	0

*Based on an average size of 29 MW (100 MMBtu/hr) and 7,000 hrs/yr of operation.

TABLE 12. NO_x EMISSION CONTROL COST DATA FOR GAS TURBINES

Control device	NO_x emissions reduction (%)	Costs (1980 $)*		
		Capital		
		New	Retrofit	O&M
New burner	30	20,000	30,300	0
Water injection	70	25,000	35,700	7,500

*Based on 1.9 MW (2,600 hp) turbine and 7,000 hrs/yr of operation.

TABLE 13. NO_x EMISSION CONTROL COST DATA FOR CEMENT AND GLASS

Control device	NO_x emissions reduction (%)	Costs (1980 $)*		
		Capital		
		New	Retrofit	O&M
LEA	20	0	5,000	0
New low NO_x burner	30	10,000	50,000	0

*Based on an average size of 15 MW (50 x 10^6 Btu/hr) and 7,000 hrs/yr of operation.

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